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Build to Order

Contractors speak out on EPC trends.

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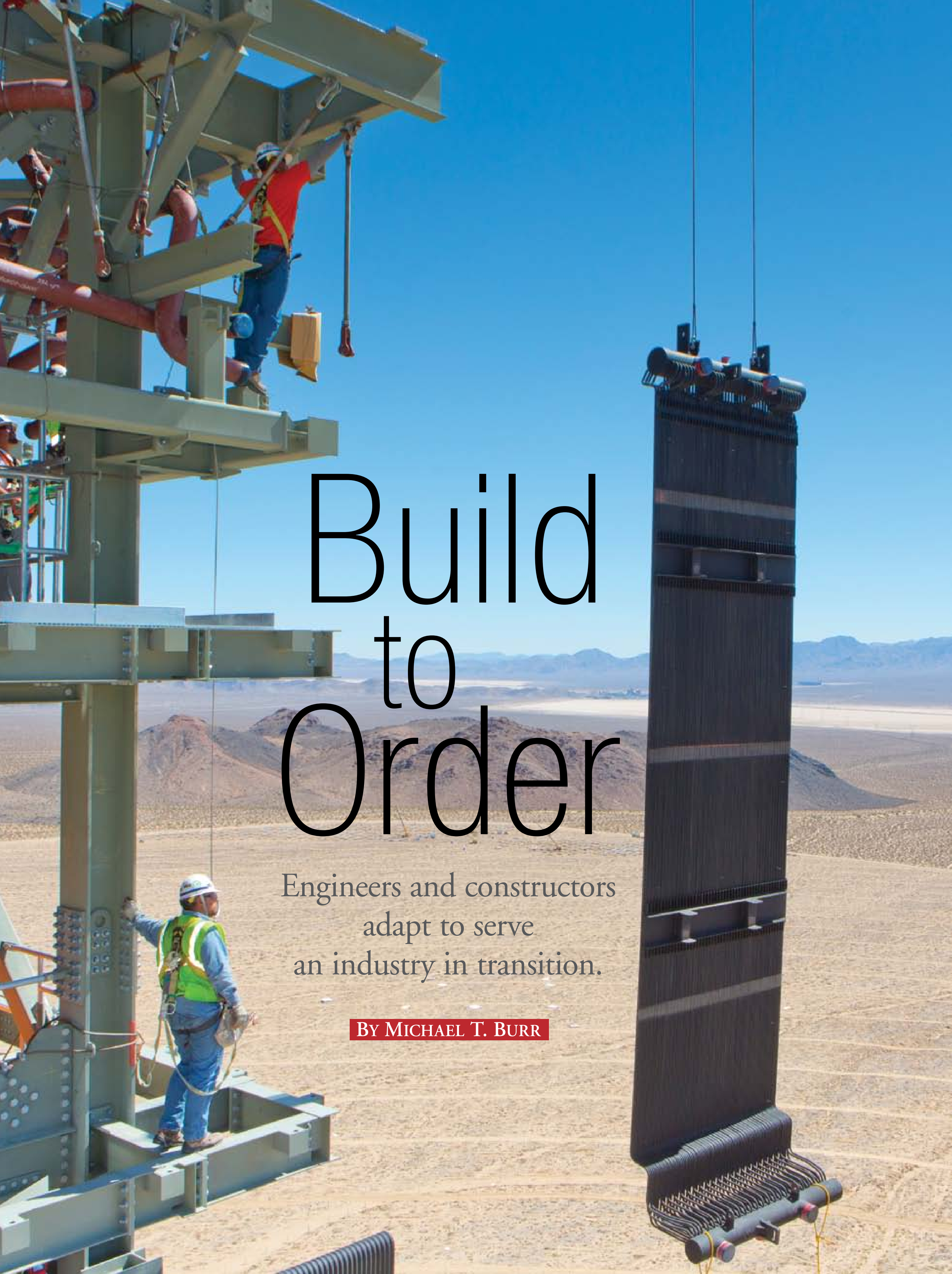

Build to Order

Engineers and constructors adapt to serve an industry in transition.

By Michael T. Burr

Courtesy of Bechtel

Back in the old days, the process of designing and building a power plant—or a transmission line or gas pipeline for that matter—was relatively straightforward. A utility company put its engineering and project management staff on the task, and they'd handle the full scope of project design, construction, and startup. They'd outsource construction to job crews, of course, but the project was handled by utility staff from beginning to end.

Then came deregulation.

As lawmakers opened up wholesale energy infrastructure to competition, a new crop of owners brought a new approach. Non-utility developers outsourced entire plants to engineering, procurement, and construction (EPC) contractors. That approach shifted risks onto third-party design-build firms, and allowed the owners to obtain non-recourse project financing on the strength of a fixed-price, date-certain contract, and a power purchase agreement (PPA) with a utility company.

It also provided access to world-class engineering and construction (E&C) skills, as well as global procurement, logistics, and project management expertise that no upstart developer could touch with a 100-foot crane. And, as it turns out, neither could even the biggest U.S. utility company.

Utilities quickly recognized that EPC skills weren't necessarily among their core value propositions, and over time utilities shrank their engineering departments until most utility engineers were focused on operations and maintenance (O&M) rather than building major new power plants. To greater and lesser degrees, the same forces have reshaped the way gas pipelines and transmission systems are built. And along the way, contractors have adapted their strategies and service offerings to suit the evolving needs of the industry—which today seems to be changing faster even than it did in the era of deregulation.

To better understand these changes, *Fortnightly* recently spoke with executives at engineering and construction firms specializing in various types of power and gas projects:

- Michael Rencheck, Areva
- Jeff Brightman, Bechtel
- Bob Bibb, Bibb Engineers Architects & Constructors
- Steve Edwards, Black & Veatch
- John Olander, Burns & McDonnell
- Alan Champagne, CH2M Hill
- David Williams, Fluor

FORTNIGHTLY: What's the state of the U.S. market for electric and gas EPC services? What kinds of projects are moving forward right now, and what's your outlook for the near and mid-term future?

Jeff Brightman, Bechtel: In power generation, inexpensive gas has really changed the whole market. It's cascading into how people make investment decisions. And if you layer on top of that the current stagnation of environmental regulations—meaning some of the latest environmental regulations have been stayed by the courts—it further favors gas investment decisions because people aren't going to make investment decisions on air quality, even for existing economically viable coal assets. And in the nuclear space, while we've done a lot of work lately uprating facilities like NextEra's, cheap gas-fired generation is now affecting investment decisions in nuclear power uprates. *[Editor's note: Completion of uprate work at NextEra's Turkey Point station this year caps a multi-site project adding 700 MW of new capacity. Also Bechtel currently is leading Xcel Energy's 71-MW uprate and refueling project at the 600-MW Monticello plant.]*

> **"We're on the edge of the next wave of activity; you can see it taking shape."**
>
> *–Bob Bibb, Bibb Engineers Architects & Constructors*

A year ago everyone was talking about air-quality projects. It was going to be the biggest facelift the coal fleet had ever seen. And now, nobody is making major investment decisions in the coal fleet. The shift has gone to gas, renewables, and maintenance and modernization work on nuclear plants.

Michael Rencheck, Areva: We see continuing modernization of the nuclear fleet with license extensions and uprates. Also after Fukushima we're seeing modernizations enabling plants to continue operating with the foremost level of safety.

The fleet is adding units at TVA's Watts Bar and Southern Company's Vogtle sites, and South Carolina Electric & Gas is adding two units at the V.C. Summer plant. TVA now is starting on a new unit at Bellefonte and we hope a second will also move forward there. But at the same time we're witnessing the closure of the Kewaunee and Crystal River stations. Kewaunee was closed due to market conditions in Wisconsin, and Crystal River because a containment building had construction difficulties that made

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it inoperable from a regulatory perspective.

Although the recession put a damper on electricity demand throughout the country, portfolio diversity is still a very important part of a strong strategy for safe, reliable, and affordable electricity. The market for fossil fuels is complex. Natural gas prices are so low that the oil and gas industry is shifting focus to oil. Some natural gas pipelines are slated to be converted to transport oil. Oil is at $90 or $100 a barrel and gas is at $3 and change. Some companies are looking at gas liquefaction projects to monetize the gas stream. Coal continues to suffer because of low gas prices. This all begs a question about increasing reliance on natural gas. With limited pipeline capacity and with arbitrage between gas for power generation and heating fuel in the dead of winter, what service will get cut? You still have to live with the capacity of the system as it is right now. *(See "No Fuel, No Power," this issue, p.20).*

To extend the life of a 1,000-MW nuclear plant for 20 years (to a 60-year total) the license process itself costs around $20 to $40 million. We see most if not all of the existing fleet wanting to extend. For extending to 80 years there's work that needs to be done replacing aging materials. But even comparing with gas you'll find nuclear a much better option than trying to build a new gas plant, from a value perspective.

However what we have seen in the market is that if there were plants looking at large-scale power uprates, with electric demand and prices so low, it doesn't make economic sense unless they need new capacity. So you see that signal in the market, pushing off uprates.


Black & Veatch in 2012 completed a flue gas desulphurization retrofit at AEP's Cardinal coal-fired station on the Ohio River.

Courtesy of Black & Veatch

Bob Bibb, Bibb EAC: Everybody in the industry was hammered by the Great Recession. It lasted about two years, and we came out of it about two years ago. Since then things have been going pretty well. We're on the edge of the next wave of activity; you can see it taking shape, but it's not clear yet whether it will turn into a big wave that you can catch.

For now, the North American market is slow. Most contractors who are dedicated to the power industry are challenged right now, unless they happen to have one of the handful of projects that's going forward. Or if you're active in upstream natural gas facilities, you might have more going on.

Alan Champagne, CH2M Hill: We're very busy right now, with a lot of IPPs and utilities expecting some growth in the market, and with the need to replace coal-fired plants. If you look at PJM and Ontario, several years ago they were concerned about whether they'd have enough power. The recession came along and capped their needs, but now they're concerned that they won't have enough capacity when demand comes back. However, in general there isn't much projected increase in demand, and we think coal plant closures are the biggest driver in the market.

> **"Nuclear [relicensing is] a much better option than trying to build a new gas plant. But with electricity prices so low, [owners are] pushing off uprates."**
>
> *–Michael Rencheck, Areva*

For many years, everyone was trying to find ways of building coal plants, developing IGCC and carbon capture technologies. But with bigger and bigger gas discoveries—even more layers of gas beneath what we're looking at now—it's possible to predict over a 20-year period that gas prices won't go up much. Couple that with the belief that coal isn't as clean, with CO2 emissions about double those of a gas plant, and there's a strong push to shut down coal and build gas-fired plants.

David Williams, Fluor: We are seeing gas-fired plants being embraced as a baseload solution more than ever before. We're seeing baseload gas plants coming, and also we see activity in large PV projects. We're looking at blocks of 45 MW and now we're even seeing them in the 100 MW-plus range. We started on some PV projects last year and they're going well. We believe there will be more for the next few years with investment tax credits still in place.

John Olander, Burns & McDonnell: The electric transmission market has been slowly evolving. In the past owners traditionally handled everything, but through attrition, mergers and acquisitions, and companies addressing their core businesses, quite a few utilities have stepped away from E&C management, which has opened the door for firms like ours. We're seeing a much bigger opportunity for program management.

On the gas side, the pipeline industry is expanding to move gas from shale plays. There are new pipeline projects coming up, but they're moving slowly because gas prices have been very low for quite some time. There's plenty of production capacity and gas to be extracted, but the price points don't allow some of these projects to move forward.

That's a difference we see between the gas and electric transmission markets. The gas market is more of an open market, where the projects chase the money. By comparison, in electric transmission, reliability expectations ensure money will be there to enhance and improve the transmission system.

The other thing is that in recent years gas pipeline incidents have gotten the attention of regulators. It's starting in the states, and ultimately we'll have federal regulations that will require pipeline pressure testing and bringing the old system up to new standards.

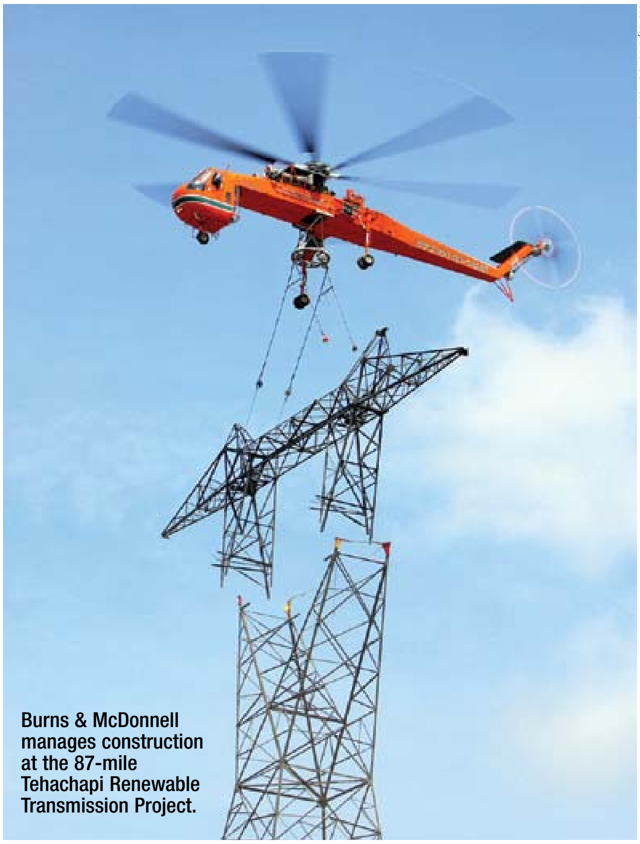
A lot of gas distribution systems in this country are very old. They were built for 30- to 50-year lifespans, and many are well beyond that. We're seeing distribution utilities replacing old cast-iron and bare steel systems. It can be labor intensive and costly, because obviously a lot of distribution pipelines are located in urban areas, where replacement takes a lot of coordination.

Steve Edwards, Black & Veatch: Generally what we see in the market is a mid-level amount of activity. It's not the strongest it's ever been, but it's not the weakest either. The market is reasonably good in power. In the gas-treatment area, it's extremely strong right now. We're very busy there with a tremendous amount of midstream work as a result of shale gas developments. Liquefaction for transportation fuels is a growing area in the United States and somewhat in Canada, and we see that continuing for the next few years.

FORTNIGHTLY: What regional variations do you see, in terms of current markets and the future outlook?

Rencheck: There are a lot of differences from region to region. California has a strong RPS and a CO2 market, so there's a dynamic market to develop renewables and phase out fossil generation. In the Southeast, utilities continue to diversify their portfolios, adding gas and nuclear capacity. In unregulated states you see very little development happening because capacity market prices aren't strong enough yet. But you see some energy efficiency projects in markets like PJM. And you see wind where the PTC is sufficient to pay for their generation.

Edwards: Renewables had been extremely strong, with uncertainty in federal policies [and developers pushing to meet project milestone deadlines]. That has tapered off a bit, but we are very active in services and EPC contracts. Much of the solar work is in the Southwest, but we're looking at a lot more distributed generation projects in other locations. We expect markets in the East to be fairly attractive for that kind of work. With more clarity on federal production tax credits (PTC), we'd expect the pace of wind projects will accelerate maybe six or eight months from now.



Courtesy of Burns & McDonnell

Burns & McDonnell manages construction at the 87-mile Tehachapi Renewable Transmission Project.

We're still seeing scrubber and baghouse retrofit projects in the Upper Midwest and the Southeast. But we're not seeing much of that work in the West at all right now.

In terms of gas-fired power, quite a few large combined-cycle projects are being discussed or are getting started in the Northeast. They aren't plentiful in other parts of the country, but there are more than there were two years ago.

Williams: Gas is strong in the South and the Mid-Atlantic, and some projects are going forward in the Midwest, Texas, and out to the West as well. If you follow the pipelines, you can see where gas projects are going.

Brightman: You have to look at the U.S. as a bunch of regional markets that are influenced by economic growth and the availability of gas pipelines. We see a lot of growth in Texas and in the Southeast driven by population shifts and some manufacturing growth. For example, we're working with Panda Energy on two projects in Texas. In the Northeast, generation is driven by coal plant retirements. The Midwest is a hopscotch of one-off projects, because there's been a decline of manufacturing.

There are specific areas where they need a plant, to make up for a retiring coal unit, but those are for specific needs rather than growth generally. Electric demand in the Midwest is expected to be flat for the next few years.

Olander: We're seeing a lot of gas distribution replacement projects in the Northeast, because the utility system is substantially older there than in the rest of the country. Gas safety upgrades also are coming in California due to state regulations. And we see gas transportation pipelines to carry gas from the Marcellus shale region in Ohio and Pennsylvania.

Bibb: We have five plants under construction with four different owners. And we're the owner's engineer on a 900-MW combined-cycle project in Pennsylvania, repowering an old 400-MW coal-fired plant. A huge amount of time and effort has been extended to develop that project, but it's not a sure thing yet. It's now going through the process of getting officially picked up by PJM. It still has to get financed, and some wrinkles need to be worked out with gas supply and power marketing. It's going to be a great project if it goes forward.

We have a lot of exciting prospects like that. Dominion is pretty far along with a 1,200-MW combined cycle plant, and is in earlier stages with another one of about the same size. We have a line on projects going forward in Texas, Florida, and California. LADWP [Los Angeles Department of Water & Power] is awarding a 550-MW combined cycle project. Those are all nice jobs but it's not like the heyday.

FORTNIGHTLY: What are you seeing in RFPs and contract terms? How are practices and requirements changing?

Champagne: What we're seeing is quite different from what occurred in the early 2000s. There was a flood of opportunities back then, and delivery times for large equipment were sometimes 30 to 36 months long. So owners would buy gas and steam turbines well in advance, in some cases not even knowing where they'd put them, because they wanted to get in line. Because of this long lead time, they wouldn't hire EPC firms to procure major equipment.

Fluor designed and built the 620-MW Jacks County gas-fired plant under an EPC contract with Brazos Electric Cooperative.

Courtesy of Fluor

Now the OEMs (original equipment manufacturers)—GE, Siemens, Mitsubishi, Alstom, etc.—have a lot of manufacturing capacity available, and so the delivery times are short. You can get the stuff in 14 to 18 months. As a result owners are asking EPC firms to select and buy the equipment. They'll provide size guidelines and let us bid out and select the most competitive offering for their scope. That means there's a lot of activity with OEMs putting bids together for multiple contractors. When two or three EPC firms are bidding on a project, the OEMs are supplying bids to everybody, and that means they're stretched because we and our competitors might be asking for something different.

Brightman: RFPs are very diverse and specific to customers' needs, based on what they see as their load profile and growth in the future. Some utility RFPs are specific to certain types of generation, but more are based on capacity and availability. Those criteria determine who will bid. If it's an RFP for capacity to serve peak load in an area where there's sun, then solar will fit. If not, then it will be some sort of gas or a mix of assets to serve demand. We're seeing RFPs that multiple players can participate in, and we're seeing RFPs for projects that can meet RPS requirements.

Also we're seeing customers taking bids for fleet-wide O&M and modernization. That's starting to move over into the coal fleet somewhat, but coal maintenance and modernization work tends to be contracted on a station-by-station basis.

"Gas transmission is more of an open market, where projects chase the money. But in electric transmission, reliability expectations ensure money will be there."

–John Olander, Burns & McDonnell

For new generation, customers are looking for EPC contractors to backstop newer technologies—to wrap the technology. We're doing that on a project for Panda, where we're using a Siemens state-of-the-art Frame combustion turbine. Siemens is providing the gas turbine, steam turbine, and other equipment, and in consortium we're wrapping the technology and balancing the risk.

Some owners are taking the technology risk and asking contractors to be an integrator. A lot of it is driven by how a project will be financed, whether on balance sheet or with [non-recourse] project financing. It's a fairly tight market for project financing, and investors like to see a single entity wrapping the project risk where they can, like in the 1990s when the project finance model was developed, and you had a single EPC contract with liquidated damages provisions for schedule and performance risk.

As for terms and conditions, because of a greater need for

Courtesy of Bechtel

Bechtel is building the worlds-largest solar thermal plant, the 377-MW Ivanpah project, for BrightSource Energy in the Mojave Desert.

flexibility to address growing renewable generation, we're seeing terms that require us to guarantee a greater range of performance. Specifically, most renewable projects don't have an efficient way to store energy, so if the wind stops or it gets cloudy, there's a need to meet demand with quick-start turbines, for example. So owners are looking to EPC contractors to stand behind quick-start requirements, which is new in the market.

Rencheck: You see a mix of things. In an EPC fixed-price mode, the contractor takes on risk, so obviously their profit margins are higher. Sometimes utilities will do pieces of a project on a fixed-price or cost-plus basis. It depends on the project, and the expertise the customer has. If it's a gas-fired plant at a greenfield site, it makes sense to use a model for building a plant the same way every time. But if you're doing a retrofit or repowering, it's harder, and contracting mechanisms will reflect that.

Sometimes we do nuclear projects in pieces; we'll do the engineering portion until we get about 65-percent done, and then we'll provide a full-price contract. We do that in joint venture with other companies, like Day & Zimmerman. It might be at cost-plus, with some portion of the fee at risk, depending on how many different factors are involved. Is the plant in the middle of an outage? How well can the utility control the surrounding work?

The ultimate goal is to provide value to the customer. We'll help the customer optimize the outage, with service and repair work. We have crews that repair steam generators, reactors, and vessel heads. They can do all the welding and inspections. One utility was facing heavy component replacements, and we helped them save tens of days on an outage window by optimizing the process.

Edwards: Generally the contract structures we're seeing are similar to those we've seen in the past. We're seeing more of a tendency for us to bring the technology, but owners often want to be involved in selecting it; they want a lot of transparency in the choice of OEMs.

In some states we're seeing all-source bids [in which the utility seeks bids from any type of resource]. Those are driven by state public utility commissions. Rather than having the utility define it, they want the RFP to prove what's the least cost for the consumer, and you'll see responses from A to Z, including demand response.

"Owners are looking to EPC contractors to stand behind quick-start requirements, which is new in the market."

–Jeff Brightman, Bechtel

Bibb: In a buyer's market like today's, more utilities are using all-source solicitations. You have different technologies and fuels, and it can come from one contract or 10 contracts. It can be part EPC, part IPP, and partly utilities selling blocks of power, or selling facilities to each other. It can come from power marketing companies that don't own assets, but just buy and sell power. And the utility might compare all those third-party proposals against its self-build option.

Fluor built a 30-MW PV project for SunEdison at a San Antonio Water System water treatment site.

Courtesy of Fluor

Courtesy of Fluor

Some of these RFPs are very non-specific. We went through this on a biomass project for a utility. I was reluctant to go through the expense of preparing an EPC bid, because it's horribly expensive to do engineering and put together a competitive bid on something that isn't designed yet. Not only were we competing against other bidders to build the biomass plant, but the utility was also soliciting bids for gas turbines, and for IPPs to provide the same capacity under a PPA, and for other utilities to sell power to them.

When contractors are all busy, they'll never do that. But in a buyer's market, the owner can have very demanding terms and impose high risks, and still get a pretty good response. Suppliers and OEMs will do tremendous things and take tremendous risks to win a job at a competitive price. But there are only a handful of players that can hold a $500 million EPC contract, let alone a billion-dollar contract. So when the pendulum swings the other way and it's a seller's market, they're all busy, and prices can go through the roof like they did before the recession.

Champagne: I don't see a lot of difference between contracts now and five years ago. Projects are bigger, and so the potential losses are bigger. If you miss a schedule on an 800-MW plant, it's more costly than 10 years ago when it would've been a 400-MW plant.

However we have seen some changes in the market. We used to see more competition from teams of engineers in joint venture with construction contractors. Sometimes the contractor would take the lead if they had the bigger balance sheet, and sometimes it was split between the two. But with larger projects and larger dollar values, a lot of companies that were engineers only didn't have the capacity to take that role in a joint venture. The risk was too high for a company of their size, and so a lot of those firms have moved toward being an owner's engineer, more of a consultant role. As utilities have eliminated their staffs of engineers and project supervisors, they've outsourced that work to engineering firms.

Today we tend to compete against companies that do the same things we do—all the engineering, construction, and startup, in-house.

One thing we're all concerned about is speculation in the market. We'll get an RFP from a company that's running the bidding process in parallel with permitting and approvals, and in some instances also the power purchasing process. So these things are all proceeding in parallel, and if one of them encounters bumps in the road, the project might be canceled or delayed by a year. We were active on two projects last year that were canceled because they hit snags. We see a lot of people looking to build plants just in PJM, and they're all looking to be the low-cost provider. We have to put on our thinking caps and ask the right questions. Why is this project better than the one next door? How do we assure ourselves this is the right opportunity for us to participate? For some projects, putting together a bid can cost us half a million dollars. You can't bid on many projects like that if they keep getting canceled.

"Customers come to us for large PV projects because they're procurement nightmares."

–David Williams, Fluor

Olander: On the gas side, in addition to the traditional contracting model, a need has evolved for program management support, due to project size and complexity. In this role, someone steps in on behalf of the owner and works to handle a portfolio of projects, perhaps over a long period of time and over large distances. You're working with the owner and assuming a lot of traditional owner responsibilities, such as project

Bechtel is building two combined-cycle gas turbine projects in Texas for Panda Power.

Photo courtesy of Panda Power Funds

controls, construction management, hydrostatic testing, QA-QC (quality assurance and quality control)—things that typically an owner might handle themselves, but due to the complexity of projects in size and nature, they're seeking a contractor to help wrap everything together.

On the transmission side, one thing that's affected our customers, and therefore us, is that FERC has taken away rights of first refusal (ROFR) among utilities and opened the process of building transmission to non-incumbents. That's still a work in progress; FERC hasn't yet announced its determination on everybody's plans. *[Editor's note: After this interview, and just before this issue went to press, FERC ruled on the merits of Order 1000 compliance filings and ROFR claims by MISO and PJM.]* All of the RTOs, ISOs, and other regional transmission operators have filed plans for how they'll assign projects going forward. We're seeing a lot of activity among incumbents and non-incumbents forming new entities and partnerships to chase some larger projects around the country. We'll end up with teams of developers, owner-operators, EPC firms, and equity finance partners going after projects that previously would've gone right to incumbents. The difference is that incumbents wouldn't have had to put those teams in place until later in the process. It's moved the teaming process forward, as part of what it takes to go and get a project. FERC Order 1000 is going to push a lot of innovative contracting.

When an RFP hits our desk, we ask, 'What's the likelihood that the project will move forward?' On the regulated transmission side, the vast majority of projects do move forward if they've gotten to the point where the owner issues an RFP, because typically they won't do that unless they have some confidence they'll receive their rights of way and permits. You're at risk for delays, but eventually it will move forward. But on the deregulated side, there's definitely a higher risk, because not only do you need rights of way and permits, you need a buyer and a seller.


Courtesy of Burns & McDonnell

There are two main models for ISOs and RTOs. There's the sponsorship model, where if an entity brings a project forward and it's selected, then that entity would be assigned to build the project. PJM uses the sponsorship model, but a number of other ISOs are going with a competitive model. That means the ISO announces what the project is, and it's open competition for entities to pursue that project. You're bidding as a team to chase a project, competing against others, and ultimately there will be only one winner. *(See "First Refusers," February 2013.)*

"For some projects, putting together a bid can cost us half a million dollars. You can't bid on many projects like that if they keep getting canceled."

–Alan Champagne, CH2M Hill

As a contractor, there's a similar level of effort for both, and there's no recourse for recovering your costs if you're not selected as the winning team. That's something regulated utilities, staying in their footprint, haven't had to address. It brings a cost, because if three entities are chasing the same thing, you're paying for that effort three times. But in a competitive industry, the market will drive efficiencies, and the expectation is that those efficiencies will outweigh the additional costs of the process.

FORTNIGHTLY: What about alternatives to traditional transmission projects? Are you seeing any activity on innovative things like the Tres Amigas project?

Olander: Innovative projects tend to be truly developer-originated projects, as opposed to regulated projects. Examples like Tres Amigas, Clean Line Partners, Pattern Energy—those entities are looking for buyers and sellers, someone who will purchase rights from them. FERC Order 1000 established that


Burns & McDonnell managed a 437-mile transmission project for Central Maine Power.
Courtesy of Burns & McDonnell

as a goal, and it will happen, but not until there's some confidence among developers that if they propose a project it will remain with them, and it won't just go to the common good, for cost. That's a couple of years off.

FORTNIGHTLY: Many of the new projects being built today are solar and wind farms. Is this a good market for EPC firms?

Champagne: We're providing engineering services in the solar market particularly, and also we provide some support in all the other renewables, like biomass and wind. But we're not building as an EPC contractor in that area. Solar and wind is a much simpler business. It's repeatable—putting up a wind farm with multiple turbines, or even solar projects. You're putting in racks. It's a repeatable thing, easy enough for a smaller, less-skilled contractor. And only 2 percent of the value of the contract is engineering, and even labor is only 13 to 15 percent. With PV, materials and equipment make up about 80 percent of the cost of the project. It's much better for the manufacturer to be the EPC contractor, because they can go out and hire a constructor to do that 13-percent value of the project. That's why we haven't gone full-bore into that area.

Williams: You don't see a lot of EPC contracts for onshore wind farms, because those projects are driven by equipment. They're fairly easy to install, and there aren't a lot of different pieces and components requiring management. But you do see EPC contracts for PV and solar thermal plants. With PV plants, you have panels and inverters—and a lot of them—and someone needs to manage the project. It's about material handling and logistics rather than engineering. Manufacturers don't have large balance sheets, and these are huge projects, so customers need someone who can put the project together and wrap it up so they don't have to take that risk.

Customers come to us because they see these projects are procurement nightmares. They're bringing in components from various countries, and many of our clients aren't set up to manage logistics and surveillance processes. So they look to a company with procurement strength, sometimes in early stages for multiple projects.

Also we're seeing a new market for O&M on solar facilities. We just announced an award for an LS Power PV project in Arizona. We're in the middle of EPC on it and we just signed the O&M contract. Facilities like this are located in areas where there isn't a huge population, and it's not in the developer's backyard, so staffing is a problem. That's why they come to a company like Fluor. Operations have always been a strength for us, and a lot of our competitors too.

Brightman: At Bechtel we've evolved in the last three to five years to focus on renewables. We previously focused mostly on fossil and nuclear power, but now it's renewables. We're building the Ivanpah project, for example, which is the largest solar thermal project in the world. It's now roughly 80-percent complete, and the first unit is scheduled to go commercial late this summer. Also we're working on the largest PV project in California, and we're looking at offshore wind, and wind in general, because the market has grown in the United States. We're taking a balanced approach, looking at combined cycle and integrating it with solar and wind, and looking at emissions reduction projects at existing plants.

Solar thermal plants are different from wind or PV, because about 60 to 70 percent of the project is a traditional thermal power plant. So we bring the renewable strength for the mirror portion and the strengths of a thermal business for the power plant portion.

The EPC contract is a smaller piece of a PV or wind project. But as the projects have gotten bigger, owners have become more sophisticated, and they're demanding, quite frankly, higher attention to quality and safety. That plays to our strengths, but it has caused us to go back and look at weaning our E&C approaches so we're competitive in those markets. We have a different execution model for PV and wind projects. They're different from other types of power projects, so we've taken lessons from our communications business. It takes a very lean approach.

Bechtel is building the Oakland to Lanfine transmission project for ATCO Electric in Alberta, Canada.

Courtesy of Bechtel

"Gas liquefaction for transportation fuels is a growing area, and we see that continuing for the next few years."

–Steve Edwards, Black & Veatch